GREENFIELDS PETROLEUM CORPORATION

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE DATE: DECEMBER 31, 2020

September 18, 2021

ABBREVIATIONS

	Oil and Natural Gas Liquids		Natural Gas
bbl	barrel	Mcf	thousand cubic feet
bbl/d	barrels per day	MMcf	million cubic feet
Mbbl	thousands of barrels	Bcf	billion cubic feet
boe	barrels of oil equivalent, including barrels of crude oil and natural gas, unless otherwise indicated	Mcf/d	thousand cubic feet per day
boe/d	barrels of oil equivalent per day		
Mboe	thousand boe		
NGL	natural gas liquids		
MMBtu	million British thermal units		
API	American Petroleum Institute		

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic meters	28.317
Cubic meters	Cubic feet	35.315
Bbls oil	Cubic meters	0.159
Cubic meters	Bbls oil	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

EXCHANGE RATES

Except as otherwise indicated, all dollar amounts referenced in this Statement of Reserves Data and Other Oil and Gas Information are expressed in United States dollars. The following table sets forth: (i) the rates of exchange for United States dollars expressed in Canadian dollars, in effect at the end of each of the periods indicated; and (ii) the average of exchange rates during such periods, in each case based on the noon rate reported by the Bank of Canada.

	Year Ended December 31, 2020	Year Ended December 31, 2018	Year Ended December 31, 2017
Rate at end of period	1.2978	1.3642	1.2545
Average noon spot rate during period	1.3257	1.2957	1.2986

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

Reserves Categories

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

"**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned. In multi well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities andcompletion intervals in the pool and their respective development and production status.

"**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves.

"**Possible**" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The following terms, used in the preparation of the BEOC Report and this document, have the following meanings:

"**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

"**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

A) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

B) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

C) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

D) provide improved recovery systems.

"**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

A) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

B) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

C) dry hole contributions and bottom hole contributions;

D) costs of drilling and equipping exploratory wells; and

E) costs of drilling exploratory type stratigraphic test wells.

"**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may betreated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin","trend", "province", "play" or "area of interest".

"**future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using or forecast prices and costs.

“**gross lease**” means:

A) in relation to the Corporation’s interest in production or reserves, its “company gross lease reserves”, are it’s working interest (operating or non-operating) marketable share, before deduction of royalties and without including any royalty interests of the Corporation;

B) in relation to wells, the total number of wells in which the Corporation has an interest; and

C) in relation to properties, the total area of properties in which the Corporation has an interest.

“**light crude oil**” means crude oil with a relative density greater than 31.1 degrees API gravity.

“**medium crude oil**” means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

“**natural gas**” means a naturally occurring mixture of hydrocarbon gases and other gases.

“**NGL**” or “natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, and condensates.

“**net**” means:

A) in relation to the Corporation’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation’s royalty interests in production or reserves;

B) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and

C) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“**non-associated gas**” means an accumulation of natural gas in a reservoir where there is no crude oil.

“**operating costs**” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“**production**” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“**property**” includes:

A) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

B) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

C) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**property acquisition cos**ts" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

A) costs of lease bonuses and options to purchase or lease a property;

B) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

C) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation, or injection for combustion.

"**solution gas**" means natural gas dissolved in crude oil.

"**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

ADDITIONAL DEFINITIONS

Wherever used in this Statement of Reserves Data and other Oil and Gas Information, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

"Azerbaijan" means the Republic of Azerbaijan;

"**Bahar Energy**" means Bahar Energy Limited, a company incorporated in the Jebel Ali Free Zone, Dubai, UAE, a 100% wholly owned subsidiary of the Corporation;

“**Bahar Gas Field**” means the gas field located in the offshore Caspian Sea area of Azerbaijan that is the subject of the ERDPSA consisting of 45 offshore platforms;

“**BEOC**” means Bahar Energy Operating Company Limited, a company incorporated in the Jebel Ali Free Zone, Dubai, UAE, a 100% wholly owned subsidiary of Bahar Energy;

“**Company**” or “**Corporation**” or “**GPC**” means Greenfields Petroleum Corporation;

“**Contractor Parties**” means, collectively, SOA and Bahar Energy as contractors under the ERDPSA;

“**ERDPSA**” means the exploration, rehabilitation, development and production sharing agreement, which includes the Bahar Gas Field and the Gum Deniz Oil Field, dated December 22, 2009, among Bahar Energy, SOCAR and SOA;

“**Exploration Area**” means the contract exploration area referred to as the Bahar-2 area as specified in the ERDPSA;

“**Gum Deniz Oil Field**” means the oil field located in the offshore Caspian Sea area of Azerbaijan that is the subject of the ERDPSA;

“**NI 51-101**” means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

“**Rehabilitation Area**” means the rehabilitation area in the Gum Deniz Oil Field and the Bahar Gas Field as specified in the ERDPSA;

“**SOA**” means SOCAR Oil Affiliate;

“**SOCAR**” means the State Oil Company of the Republic of Azerbaijan; “UAE” means the United Arab Emirates;

“**United States**” or “**U.S.**” means the United States of America, its territories and possessions, any state of the United States of America and the District of Columbia.

“**BEOC**” means BEOC Subsurface Department, led by GRR Larijani an independent qualified reserves evaluator; and

“**BEOC Report**” means the report of BEOC dated September 18, 2020 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2020;

DISCLOSURE OF RESERVES DATA

The BEOC Report was prepared in accordance with SPE/PRMS standards (Society of Petroleum Engineers/Petroleum Resources Management System). As such this report is compliant with SEC, CPR (Competent Person’s Report) requirements for LSE (London Stock Exchange) and NI 51-101 and the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time (the “COGE Handbook”). The BEOC Report estimates the reserves of Bahar Energy as of December 31, 2020 (which includes the wells, lands, reserves, facilities, equipment and other assets including the Bahar Gas Field and the Gum Deniz Oil Field) which it holds pursuant to the ERDPSA. The estimated reserves included in the BEOC Report include all of Bahar Energy’s interest in the ERDPSA. TheCorporation owns a 100% interest in Bahar Energy who in turn owns an 80% participating interest in the ERDPSA, and, as such, the reserve estimates and other data provided which are derived from the BEOC Report reflect the Corporation’s 100% interest in Bahar Energy.

Information presented herein is presented in accordance with the requirements of Form 51-101F1.

The tables below are a summary of the oil, NGLs and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the BEOC Report based onconstant and forecast price and cost assumptions. The tables summarize the data contained in the BEOC Report and as a result may contain slightly different numbers than such report due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by BEOC**. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by** BEOC **represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

Boe's may be misleading particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

The BEOC Report is based on certain factual data supplied by the Corporation and BEOC's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to BEOC and accepted without any further investigation. BEOC accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Corporation for the year ended December 31, 2020 include a full year of operating data on the properties of the Corporation.

Summary of Oil and Natural Gas Reserves as of December 31, 2020 – Forecast Prices and Costs

Azerbaijan

	Gross Lease Reserves (1)			**Net Reserves (2)**		
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Conventional Natural Gas**	**Light and Medium Crude Oil**	**Natural Gas Liquids**	**Conventional Natural Gas**
	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mmcf
Proved						
Developed Producing	935	113	38,728	430	52	17,815
Developed Non-Producing	6,602	353	120.923	3,037	162	55,625
Undeveloped	1,804	148	50,808	830	78	23,372
Total Proved	**9,341**	**614**	**210,459**	**4,297**	**292**	**96,811**
Probable	20,947	641	219,689	9,939	307	105,358
Total Proved plus Probable	**30,288**	**1,255**	**430,148**	**14,235**	**599**	**202,170**
Possible	4,189	128	44,030	2,314	74	25,436
Total Proved plus Probable plus Possible	**34,477**	**1,383**	**474,178**	**16,549**	**673**	**227,605**

Notes:

(1) "**Gross Lease Reserves**" are Bahar Energy's working interest and marketable share of the Rehabilitation Area's reservoir volumes before deduction of royalties and government's share of production.

(2) "**Net Reserves**" are Bahar Energy's Gross Lease Reserves after deduction of royalties and government's share of production.

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs

Azerbaijan

	0%	5%	10%	15%	20%
		Discounted At [1]			
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	26,324	17,324	12,026	8,725	6,568
Developed Non-Producing	184,265	121,265	84,179	61,075	45,977
Undeveloped	52,648	34,647	24,051	17,450	13,136
Total Proved	**263,238**	**173,236**	**120,255**	**87,250**	**65,681**
Probable	802,515	478,739	304,852	204,877	143,940
Total Proved plus Probable	**1,065,753**	**651,975**	**425,107**	**292,127**	**209,621**
Possible	210,746	137,881	96,665	71,507	55,132
Total Proved plus Probable plus Possible	**1,276,499**	**789,855**	**521,772**	**363,634**	**264,757**

Note:

(1) The amounts included herein are the same on a before and after tax basis because, pursuant to the ERDPSA, an income tax equivalent to 20% of the profit is paid by SOCAR on behalf of the Contractor Parties to the government of Azerbaijan. Any US taxes will be partially offset by the tax credits. In addition, the Contractor Parties are exempt from all other taxes, duties and royalties in Azerbaijan, other than certain customs fees, personal income tax and contributions to the state social insurance funds of Azerbaijan.

	Unit Value before Income Tax [1] Discounted at 10% ($/boe)
Proved	
Developed Producing	3.48
Developed Non-Producing	6.75
Undeveloped	5.01
Total Proved	**5.80**
Probable	10.96
Total Proved plus Probable	**8.76**
Possible	14.59
Total Proved plus Probable plus Possible	**9.46**

Note:

(1) Unit values are based on Net Reserves.

Additional Information Concerning Future Net Revenue – Undiscounted Forecast Prices and Costs [1]Azerbaijan

	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes
	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Total Proved	1243	247	538	129	47.5	263
Total Proved plus Probable	3321	917	861	210	50.0	1065
Total Proved plus Probable plus Possible	3736	1064	902	221	60.0	1276

Note:

(1) No column concerning future income taxes or future net revenue after income taxes has been provided since, pursuant to the ERDPSA, an income tax equivalent to 20% of the profit is paid by SOCAR on behalf of the Contractor Parties to the government of Azerbaijan. Any US taxes will be partially offset by the tax credits. In addition, the Contractor Parties are exempt from all other taxes, duties and royalties in Azerbaijan, other than certain customs fees, personal income tax and contributions to the state social insurance funds of Azerbaijan.

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes [3] (Discounted at 10%/Year)	Unit Value Before Income Taxes [4] (Discounted at 10%/Year)
	(MM$)	($/boe)
Proved		
Light and Medium Crude Oil[1]	65	14.2
Conventional Natural Gas[2]	55	3.4
Proved plus Probable		
Light and Medium Crude Oil[1]	279	18.8
Conventional Natural Gas[2]	146	3.9

Notes:

(1) Including solution gas and associated by-products.
(2) Including by-products but excluding solution gas.
(3) Other revenue and costs of the Corporation not related to a specific production group have been allocated proportionately to production groups.
(4) Unit values are based on the Corporation's Net Reserves.

Pricing Assumptions - Forecast Prices and Costs

BEOC used the following pricing and inflation rate assumptions as of December 31, 2020 in its evaluation contained in the BEOC Report in estimating GPC's reserves data using forecast prices and costs.

	Brent Oil Price [1]	Net Realized Oil Price [2]	Natural Gas Contract Price	Net Realized NGL Price [2]	% Cost Escalation Operating Expenses [3]	Inflation rate
	($/bbl)	($/bbl)	($/MMBTU)	($/bbl)	(%)	(%)
Forecast						
2021	65.00	58.10	2.69	58.10	0.0	0.0
2022	70.00	62.80	2.69	62.80	2.0	2.0
2023	70.00	62.80	2.69	62.80	2.0	2.0
2024	72.50	65.20	2.69	65.20	2.0	2.0
2025	75.00	67.50	2.69	67.50	2.0	2.0
2026	75.00	67.50	2.69	67.50	2.0	2.0
2027	75.00	67.50	2.69	67.50	2.0	2.0
2028	75.00	67.50	2.69	67.50	2.0	2.0
2029	75.50	67.90	2.69	67.90	2.0	2.0
2030	75.90	68.40	2.69	68.40	2.0	2.0
2031	76.40	68.80	2.69	68.80	2.0	2.0
2032	76.80	69.20	2.69	69.20	2.0	2.0
2033	77.30	69.60	2.69	69.60	2.0	2.0
2034	77.70	70.10	2.69	70.10	2.0	2.0
2035	78.20	70.50	2.69	70.50	2.0	2.0
2036	78.60	70.90	2.69	70.90	2.0	2.0
2037	78.90	71.30	2.69	71.30	2.0	2.0
2038	79.50	71.80	2.69	71.80	2.0	2.0
2039	80.00	72.20	2.69	72.20	2.0	2.0
2040	80.00	72.20	2.69	72.20	2.0	2.0

Notes:

(1) Per GLJ Petroleum Consultants Crude Oil Price Forecast effective January 1, 2020.

(2) Net Realized Oil Prices are calculated at approximately 94% of GLJ forecast Brent Crude Price less $3.00/bbl transportation and marketing costs.

(3) Escalation rates are based on the Society of Petroleum Evaluation Engineers annual survey of projected expenses and costs.

The weighted average net realized sales prices for the year-ended December 31, 2020 were $2.69/Mcf for natural gas and $35.61/bbl.

Reconciliations of Changes in Reserves and Future Net Revenue

Company Gross Reserves Reconciliation (1)(2)

The following table sets forth reconciliation of GPC's gross proved reserves, gross probable reserves and gross proved plus probable reserves at December 31, 2020, against such reserves as at December 31, 2018, based on forecast price and cost assumptions.

Azerbaijan

Proved	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**13,620**	**162,762**	**766**	**41,513**
Extensions	-	-	-	-
Improved Recovery	-	-	-	-
Technical Revisions	-5,957	-13,080	-258	-4,035
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-191	-7,475	-17	**-1,454**
Balance at December 31, 2020	**7,472**	**168,367**	**491**	**36,024**

Probable	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**13,723**	**174,814**	**949**	**43,808**
Extensions	-	-	-	-
Improved Recovery	-	-	-	-
Technical Revisions	3,035	937	-436	2,755
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-	-	-	**-**
Balance at December 31, 2020	**16,758**	**175,751**	**949**	**46,563**

Proved plus Probable	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**27,343**	**337,576**	**1,715**	**85,321**
Extensions	-	-	-	-
Improved Recovery	-	-	-	-
Technical Revisions	-2,922	14,017	-694	27,054
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-191	-7,475	-	**-1,280**
Balance at December 31, 2020	**24,230**	**344,118**	**1,004**	**82,587**

Notes:

(1) Opening Balance has been adjusted to reflect changes made to the COGE Handbook related to the reporting of the Corporation's Gross Reserves associated with Production Sharing Contracts.

(2) Opening Balances were separately prepared by GLJ Petroleum Consultants Ltd., an independent qualified reserves evaluator.

Company Net Reserves Reconciliation (1)(2)

The following table sets forth reconciliation of GPC's net proved reserves, net probable reserves and net proved plus probable reserves at December 31, 2020, against such reserves as at December 31, 2019, based on forecast price and cost assumptions.

Azerbaijan

Proved	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**11,032**	**138,000**	**641**	**34,673**
Extensions	-	-	-	-
Improved Recovery	-	-	-	-
Technical Revisions	-6,544	-33,714	-332	-12,495
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-191	-7,475	-17	-1,454
Balance at December 31, 2020	**4,297**	**96,811**	**292**	**20,724**

Probable	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**5,614**	**71,400**	**501**	**18,015**
Extensions	-	-	-	-
			-	
Improved Recovery	-	-	-	-
Technical Revisions	4,325	33,958	-194	9,791
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-	-	-	-
Balance at December 31, 2020	**10,055**	**105,451**	**308**	**27,806**

Proved plus Probable	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
	(Mbbls)	(MMcf)	(Mbbls)	(Mboe)
Balance at December 31, 2019	**16,646**	**209,400**	**1,142**	**52,688**
Extensions	-	-	-	-
Improved Recovery				
Technical Revisions	- 2,219	244	-526	-1,680
Discoveries	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Economic Factors	-	-	-	-
Production	-191	-7,475	-17	-1,454
Balance at December 31, 2020	**14,236**	**202,169**	**599**	**48,530**

Notes:

(1) Opening Balance has been adjusted to reflect changes made to the COGE Handbook related to the reporting of the Corporation's Net Reserves associated with Production Sharing Contracts.

(2) Opening Balances were separately prepared by GLJ Petroleum Consultants Ltd., an independent qualified reserves evaluator.

Undeveloped Reserves

The following discussion generally describes the basis on which GPC attributes proved and probable undeveloped reserves and its plans for developing those undeveloped reserves. Undeveloped reserves are attributed by BEOC in accordance with standards and procedures contained in the COGE Handbook.

The majority of these reserves are planned to be on stream within two to five years. In some cases, it will take longer than two years to develop these reserves. In addition to the receipt of adequate and timely funding, there are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion formation is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to weather conditions and regulatory approvals).

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied in, wells drilled near the end of the fiscal year or wells further away from GPC gathering systems. In addition, such reserves may relate to planned infill drilling locations.

The table sets forth the proved undeveloped reserves volumes that were first attributed in each of the three most recent financial years.

	Company Gross Reserves First Attributed by Year-end			
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Barrels of Oil Equivalent**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)
2018	7,669	455	25,442	12,364
2019	9,450	420	18,497	12,336
2020	1,804	148	50,808	10,420

Note:

(1) 2018 and 2019 Balances were separately prepared by GLJ Petroleum Consultants Ltd., an independent qualified reserves evaluator.

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

The table sets forth the probable undeveloped reserves volumes that were first attributed in each of the three most recent financial years.

	Company Gross Reserves First Attributed by Year-end			
	Light and Medium Crude Oil	**Natural Gas Liquids**	**Natural Gas**	**Barrels of Oil Equivalent**
	(Mbbls)	(Mbbls)	(MMcf)	(Mboe)
2018	11,222	1,546	123,832	33,407
2019	17,025	1,186	218,518	54,631
2020	20,947	641	219,689	52,203

Note:

(1) 2018 and 2019 Balances were separately prepared by GLJ Petroleum Consultants Ltd., an independent qualified reserves evaluator.

Significant Factors or Uncertainties Affecting Reserve Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering or economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. GPC reserves are evaluated by BEOC, an independent consulting firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can either be positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecasted prices and costs only) and proved plus probable reserves (using forecast prices and costs only).

Azerbaijan

	Development Costs	
	Proved Reserves	**Proved plus Probable Reserves**
	(MM$)	(MM$)
2021	1.76	3.44
2022	6.94	17.04
2023	61.87	93.28
2024	43.38	56.44
2025	10.67	25.10
2026	1.35	7.44
Remaining Years	2.95	6.88
Total Undiscounted	**128.91**	**209.61**

GPC typically utilizes three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favorable terms. The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and may reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make the development of a property uneconomic.

Oil and Gas Properties

The following is a description of the oil and gas properties in which the Corporation has an indirect interest through Bahar Energy's 80% participating interest in the ERDPSA.

The properties associated with the ERDPSA are related to oil and gas production in the shallow waters of the Caspian Sea south of the Absheron Peninsula located about 15 kilometers from downtown Baku, Azerbaijan. The facilities include 89 offshore platforms, multiple pipelines and 16.8 kilometers of steel causeways with well pads from an offshore island south into the shallow waters of the Caspian Sea. One main collector pipeline carries fluids produced from the Gum Deniz Oil Field across Gum Island to separation facilities on the mainland. Four pipelines transport gas and liquids from the Bahar Gas Field directly to gas separation facilities located on the mainland.

Gum Island, lying 2.5 kilometers offshore, is connected to the mainland by a stone and paved causeway. This island houses the main operating offices, warehousing and equipment storage, and a marine base for offshore operations. The main fluid and gas handling facilities including oil and gas storage, separation, compression and metering stations are all located onshore on the mainland, and are therefore not subject to the offshore operating environment.

Natural gas production from the Bahar Gas Field is brought onshore via three parallel flow lines, two 12-inch and one 16-inch, and then passes through multi-stage two-phase gas/liquids separation facilities.

Depending on the destination market, the sales gas then flows directly into a commercial sales line or is compressed and passes into other commercial sales lines which feed other segments of the domestic gas markets.

All production from the Gum Deniz Oil Field is transported via a main collector line over the causeways to the mainland where oil, water and gas are separated through a multi-phase system. Oil is stored and later transported by pipeline to the SOCAR-operated Surakhany tank farm some 7 kilometers from the Company's storage facility. The gas production from the Gum Deniz Oil Field is used as fuel gas by BEOC in ERDPSA operations or is otherwise added to the compression facilities where it is compressed for the high-pressure gas-lift system.

Many of the producing and planned well re-entries have wellheads and platforms, which have been severely neglected over the last 15 to 20 years and require maintenance, cleanup and repair. Much of this infrastructure has not seen maintenance or repair expenditure after investment was diverted to Western Siberia before the collapse of the Soviet Union.

The Exploration Area had a three-year exploration phase with a one-year extension available, during which Bahar Energy was required to shoot 60 kilometers of 3D seismic and drill one well in order to maintain its rights in the Exploration Area. The Exploration Area may be relinquished if non-commercial quantities of hydrocarbons are not discovered.

Currently there are 41 producing wells, 29 of which are in the Gum Deniz Oil Field and produce oil with associated gas and 12 of which are located in the Bahar Gas Field and produce natural gas with condensate. For Bahar Energy's ownership only, another 226 wells are shut in. No wells have been plugged and abandoned.

Bahar Gas Field, Republic of Azerbaijan

Bahar Gas Field lies in the Caspian Sea about 25 kilometers off the coast of the Absheron peninsula. It currently consists of 45 offshore platforms. A central processing and metering platform gathers the gas and liquids for onward transport via four 12-inch pipelines to the shore-based gas and liquid handling facilities. Each wellhead platform has a small separate adjacent platform extension for housing operations personnel. All record keeping and field operations are conducted offshore and personnel are transferred by crew boat on various rotational schedules. The platforms are built on 24 to 30 pilings each in an average water depth of 20 meters. BEOC has rehabilitated the platforms and infrastructure necessary for production operations. Many of the other platforms and infrastructure will be usable after refurbishment is undertaken. Workers and equipment is brought to and from the platforms by crew and crane vessels. Crew vessels rely on boat docks and gangways for platform access, so access is weather dependent. Roughly 200 wells were drilled in the Bahar Gas Field of which 121 wells have been retained. Currently 8 wells are producing natural gas and condensate. The platforms have testing facilities, but production is then recombined for flow to the facilities onshore.

Gum Deniz Oil Field, Republic of Azerbaijan

The Gum Deniz Oil Field is located just south of the Absheron peninsula between Gum Island and the Bahar Gas Field. The field begins on Gum Island, which is 2.5 kilometers from the mainland, and progresses southward into the Caspian Sea. Much of the field was developed from platforms connected to a 16.8 kilometers steel causeway. About 109 platforms were constructed to develop the field. The causeways allow small packages of drilling and workover equipment to be moved onto the wellhead platforms and it is easy for motorized vehicles to drive out and inspect the operations. Oil, water and gas are delivered via a main collector pipeline along the causeway, across the Island and on to the onshore treatment facilities. There are currently 30 wells producing of the 155 retained oil wells. The wells are currently producing via electrical submersible pumps or gas lift using compressed gas from the onshore gas compression facilities.

Similar to the Bahar Gas Field, many of the platforms and facilities that service the Gum Deniz Oil Field were in poor condition due to the minimal capital investments since the separation of the former Soviet Union. The wells, platforms, causeway and facilities that are necessary for production have been refurbished and are suitable and safe for oil and gas operations. This has allowed for more workovers and recompletions to be undertaken. Other platforms can be refurbished as needed to enable additional workovers or drilling.

Drilling Activity and Location of Production and Wells

Oil and Gas Wells

The following table summarizes GPC's gross and net interests through Bahar Energy as at December 31, 2020 in field wells that are producing and non-producing.

	Producing Wells				Non-Producing Wells [3]			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]	Gross[1]	Net[2]
Azerbaijan	29	23	12	10	67	54	36	29

Notes:

(1) "**Gross**" refers to all wells in which GPC has either a working interest or a royalty interest.
(2) "**Net**" refers to the aggregate of the percentage working interests of GPC in the gross wells before deduction of royalties.
(3) "**Non-Producing wells**" refers to wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons. Non-Producing wells in which GPC has an interest are located no further than 10 kilometers from existing pipelines.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which GPC has an interest through Bahar Energy and also the number of net acres for which GPC's has rights to explore, develop or exploit the potential energy resources of the Exploration Area under the ERDPSA. The initial three-year exploration term from October 1, 2010 through September 30, 2013 has expired, however SOCAR has not terminated the rights to this acreage and Bahar Energy continues to assess the economic merits of drilling an exploration well based on the results of the analysis of the 3D seismic data and further subsurface studies. Prior to any proposed drilling an exploration well, an extension to the exploration period will be obtained from SOCAR.

	Gross Undeveloped Acres[1]	Net Undeveloped Acres[1]	Net Acres Expiring Within One Year
Azerbaijan Exploration Area[2]	26,676	26,676	-

Notes:

(1) Unproved Properties have no attributed reserves as of December 31, 2020. Undeveloped acreage within properties where reserves have been booked as of December 31, 2020 has not been included.

(2) In the Exploration Area pursuant to the ERDPSA, Bahar Energy is required to acquire a minimum of 60 square kilometers of 3D seismic and potentially drill at least one exploration well should a viable drilling prospect be identified. The obligation to acquire the 3D seismic has been met and potential drilling prospects continue to be evaluated.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

Development of the Corporation's properties with no attributed reserves are subject to capital allocation constraints and influenced by many factors and uncertainties, including market prices of oil and natural gas, results of exploration and development activities in the Exploration Area, and the timing and anticipated benefits of infrastructure construction and rehabilitation activities.

Forward Contracts

The Corporation is not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas. The Corporation's primary revenues are from oil and gas sales produced in Azerbaijan under the ERDPSA. Oil is sold through SOCAR and priced, on a quality differential basis, to the U.S. dollar based Intercontinental Exchange ("ICE") Brent oil price at sales date. Beginning April 1, 2017, under an amended Gas Sales Agreement that extends the contract for five years, natural gas has been sold to SOCAR at a fixed price of $2.69/Mcf under the amended Gas Sales Agreement. At December 31, 2020, the Corporation has no outstanding financial instruments, or financial derivatives contracts subject to commodity price risk.

Additional Information Concerning Abandonment Costs

In an effort to finance abandonment of all fixed assets employed in the ERDPSA by the Contractor Parties (Bahar Energy and SOA), the parties will open a joint escrow account at a bank of good international repute to be agreed between SOCAR and the Contractor Parties. This account will be known as the "Abandonment Fund" and will be administered by the operating company in coordination with SOCAR for maximum value. All monies allocated to the Abandonment Fund will be recoverable as operating costs. In no event will the Abandonment Fund exceed 15% of all capital costs incurred in the Exploration Area and the Rehabilitation Area, respectively.

The "Protocol on the Abandonment of Fixed Assets" for the Rehabilitation Area was executed with SOCAR on December 12, 2012. The provisions of the protocol specify that an abandonment plan with cost estimate must be completed no later than one year prior to the tenth calendar year following the effective date of October 1, 2010 with funding of the Abandonment Fund to commence July 1, 2021. The calculation of the quarterly amounts to be funded into the Abandonment Fund are based on the estimated abandonment costs (limited to 15% of cumulative capital costs), cumulative production from the date the Abandonment Fund is established and estimated remaining recoverable reserves.

For the Exploration Area, no abandonment obligation exists until there has been a commercial discovery and cumulative production from this contract area reaches 50% of the recoverable reserves identified in the development plan. At that time, the same funding procedures noted for the Rehabilitation Area will be employed. There is no abandonment obligation in the event that Bahar Energy terminates the ERDPSA or if the exploration term for the Contract Exploration Area is allowed to expire.

As a result, all costs of abandonment that the Contractor Parties undertake during the term of the ERDPSA will be cost recovered under the ERDPSA. At the end of the term of the ERDPSA, all remaining abandonment obligations are transferred to SOCAR.

The Corporation cannot estimate Bahar Energy's asset retirement obligations at present, and the Corporation does not expect Bahar Energy to incur significant expenditures with respect to asset retirement obligations over the next three years. The Corporation will be liable for its share of ongoing environmental obligations. Ongoing environmental obligations are expected to be funded out of cash flow.

Tax Horizon

The Corporation does not believe that it will incur any income taxes in the intermediate term. In the United States, the Corporation expects to have operating loss carry-forward and foreign tax credits to offset the taxable income during the intermediate term. In accordance with the ERDPSA, SOCAR pays income taxes applicable to the ERDPSA on behalf of Bahar Energy to the government of Azerbaijan. As a result of these factors, the Corporation does not expect to have generated taxable income in the United States for at least four to six years, if not longer.

The Corporation does not have any income generating assets in Canada.

Costs Incurred

The following table summarizes the Corporation's gross property acquisition costs, exploration costs and development costs for the year ended December 31, 2020.

Azerbaijan

	Property Acquisitions			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total (M$)	-	-	-	5,400

Exploration and Development Activities

The Corporation did not complete, or participate in the completion of, any exploration or development wells during the year ended December 31, 2020.

For the remainder of 2020, the Corporation will focus on the reduction of operating costs, platform refurbishment and upgrades in the Bahar Gas Field to support approximately four to eight gas well recompletions and to support the start of development drilling of the NKP gas reservoir in 2022, oil and gas processing facility upgrades, installing additional ESPs in the oil field, upgrades fire, support infrastructure and safety monitoring systems.

Production Estimates

The following table summarizes the Corporation's 100% share of Bahar Energy's estimated future annual production volumes for the assets evaluated in the BEOC Report for the 12 months beginning January 1, 2021 and ending December 31, 2021 for each product type.

Azerbaijan

Field	Light and Medium Crude Oil and NGL	Conventional Natural Gas	Barrels of Oil Equivalent	%
	(bbl/d)	(Mcf/d)	(boe/d)	
Bahar, Azerbaijan	51	21,487	3,632	87
Gum Deniz, Azerbaijan	543	-	543	13
Total Proved	**595**	**21,487**	**4,175**	**100**
Bahar, Azerbaijan	0	0	0	N.A.
Gum Deniz, Azerbaijan	0	0	0	N.A.
Total Probable	**0**	**0**	**0**	N.A.

Production History

The following table on a quarterly basis for the year ended December 31, 2020, discloses the Corporation's share of average gross daily entitlement volume less compensatory petroleum volumes delivered to SOCAR.

Azerbaijan

	Three Months Ended			
	March 31, 2020	June 30, 2020	Sept. 30, 2020	Dec. 31, 2020
Light and Medium Crude Oil (bbl/d) (1)	602	546	410	513
Conventional Natural Gas (Mcf/d)	18,450	19,767	20,759	22,093
Natural Gas Liquids (bbl/d)	43	52	45	45
Total (boe/d)	**3,720**	**3,892**	**3,915**	**4,239**

Note:

(1) Light and Medium Crude Oil includes Natural Gas Liquids produced from the Bahar Gas Field which volumes are commingled with the crude oil liftings delivered to SOCAR.

Prices Received, Production Costs, Marketing Cost, and Netback – Combined

The following table on a quarterly basis for the year ended December 31, 2020, discloses the Corporation's revenue share of entitlement production after deducting for production costs and marketing costs, such as transportation and storage charges, custom and bank fees and selling expenses.

	Three Months Ended			
($ per boe)	**March 31, 2020**	**June 30, 2020**	**Sept. 30, 2020**	**Dec. 31, 2020**
Prices Received	19.17	17.06	20.31	21.38
Production Costs	19.91	18.53	15.64	12.28
Marketing Costs	0.60	0.29	0.32	0.40
Netback	**-1.44**	**-1.77**	**4.35**	**8.59**

Note:

(1) Prices Received, Production and Marketing Costs may be subject to year-end 2018 financial closing adjustments.

Average Production Volume

The following table discloses the Corporation's average daily production for the year ended December 31, 2020.

Field	**Light and Medium Crude Oil** (2)	**Conventional Natural Gas**	**Natural Gas Liquids** (2)	**Barrels of Oil Equivalent** (2)
	(bbl/d)	(Mcf/d)	(bbl/d)	(boe/d)
Bahar, Azerbaijan	-	20,478	47	3,460
Gum Deniz, Azerbaijan (1)	523	-	-	523
Total	**523**	**20,478**	**-**	**3,983**

Notes:

(1) Light and Medium Crude Oil includes Natural Gas Liquids produced from the Bahar Gas Field which volumes are commingled with the crude oil liftings delivered to SOCAR.

(2) Production volumes may be subject to year-end 2020 financial closing adjustments.

Forms 51-101F2 and 51-101F3

Form 51-101F2, Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Form 51-101F3, Report of Management and Directors on Oil and Gas Disclosure for the period ended December 31, 2020 can be found on the Corporation's website at www.Greenfields-petroleum.com.